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PROJECT NO. 52373

REVIEW OF WHOLESALE ELECTRIC MARKET DESIGN	**§ §**	**PUBLIC UTILITY COMMISSION OF TEXAS**

COMMENTS OF EOLIAN

COMES NOW Eolian and files these comments in response to the Commission's Questions for Comment filed in this proceeding on October 26, 2021.

INTRODUCTION

Eolian, formed in late 2020 as a spinoff of MAP Energy, LLC, is run by one of the oldest and most successful investor teams focused on natural gas and renewable energy in the United States. Since 2005, Eolian has invested more than $500 million of equity in the development of electricity generation in Texas which has resulted in $7 billion of direct capital investment in the state. Eolian retains an interest in 4,000 MW of operating electricity projects in ERCOT, and in addition owns and operates one of the largest standalone energy storage resources participating in the ERCOT power market today, with another 200 MW of standalone energy storage under construction across two sites in South Texas, and 1,500 MW of standalone energy storage projects in development and targeting commercial operations by 2024 across the market. Eolian's founders created the predecessor to Eolian in 2005 as part of natural gas mineral acquisition fund, and the Eolian founders managed a portfolio of Texas mineral interests with a value in excess of $1 billion. Eolian has also partnered with oil and gas majors on the development of the electricity sector in ERCOT – recently having announced a transaction in February 2021 with Total on 2,200 MW of solar and battery energy storage that has started construction in the Houston area to help meet the load growth seen in that region. Eolian's largest shareholder is Global Infrastructure Partners (GIP). Together, Eolian and GIP have more than $9 billion of equity capital invested and committed to electricity assets across the globe.

COMMENTS

A key attribute of the ERCOT market competitive market structure is its clear market signals that encourage innovation solutions to market needs with minimal regulatory command and control measures. Texans have reaped the benefit of this model, with thousands of MW of generation capacity added to the grid without customers being responsible for paying the cost of these investments – the developers, owners, and operators have taken on 100% of the financial risk of these resources. This shifting of risk has led not only to innovations to improve reliable operations of individual resources, but also to developers responding to market signals regarding what additional resources will meet the needs of the grid and using modern technologies to address those needs as well. For example, as wind generation became more saturated in West Texas, more developers shifted their focus to wind development further to the east and along the coast. The natural decrease of wind output in the middle of the day encouraged the development of significant solar resources – first in West Texas, and now in East and South Texas. Market price signals encouraged the addition of fast ramping gas fired generation and, as technology has improved and costs decreased, the addition of energy storage resources. In other words, the robust ERCOT market design is encouraging the private market to bring the resources needed to ensure reliable operations for the benefit of Texans and doing so more efficiently and at a lower cost to consumers than would result from a regulatory command and control market design such as a central or disaggregated capacity market or a fully regulated vertically integrated utility.

There is no doubt that Winter Storm Uri and the extended electrical outages that occurred was a disaster for the state and should never happen again. Taking advantage of the portfolio of resources on the ERCOT grid, including the modern technologies that are being deployed, and ensuring that ERCOT has the tools available to use those resources are the key to a more reliable electric grid.

The following are Eolian's responses to select questions posed by the Commission.

2. What modifications could be made to existing ancillary services to better reflect seasonal variability?

Ancillary services are equally important throughout all seasons for the reliable operation of the market and are required on a daily basis to manage missed forecasts and unforeseen events as well as significant generator outages. Weather-driven variability around intermittent resources such as wind and solar as well as thermal generator outages (either unplanned or for planned maintenance) is now effectively equally probable in all seasons due to a combination of human behaviors, market signals, and weather volatility. For example, June of 2021 saw the unplanned outage of Comanche Peak for multiple weeks during an early summer heatwave that resulted in concerns around reserve margins and increased market prices. This October saw a period of temperatures above the long-term average during a shoulder month where planned generator outages exceeded 20 GW, including outages at both Comanche Peak and STP. While system load during these October days was only at 55 GW rather than 70-75 GW during peak summer months, ERCOT was still required to issue multiple Advance Action Notices (AANs) over the past two weeks due to these generator outages that were taken in the shoulder months after maintaining high availability during the summer peak, thereby creating the potential for a reserve capacity deficit during peak hours of days that normally would not spark concern.

It is critical to recognize that as market participants focus on ensuring reliability during key months like July and August, that these operational decisions then create the possibility of increased market tightness during shoulder months if unforeseen events occur. A focus on "seasonal variability" may inadvertently under-emphasize the need to ensure reliability in all seasons. No source of generation or electricity production has 100% availability, and if the planned maintenance of the fleet ends up being unintentionally correlated to specific apparently 'non-risky' months, the result may actually create a higher probability of capacity shortages when other, unforeseen events (like unplanned outages) occur at those inopportune moments.

In order to ensure reliability throughout the year, aside from the largely impossible act of mandating exactly when specific dispatchable generators are allowed to take outages for maintenance, there is a simple modification that could be made to the ancillary markets that would ensure active competition to provide a sufficient supply of ancillary products out of a larger and deeper pool of resources than currently exists and create a very clear market signal for investment in capacity that is designed for ancillary markets. More importantly, as ERCOT operates the grid more conservatively, ancillary services increasingly will be needed during all seasons. This makes it vital to have the opportunity to provide products that are not correlated with the existing thermal generation fleet and that can be available when larger volumes of the thermal generating fleet are offline for maintenance. In addition, a deeper pool of potential providers of these services will increase competition and reduce the extent to which customers potentially will be exposed to paying higher costs for ancillary services.

Recommended Modifications to Existing Ancillary Services:

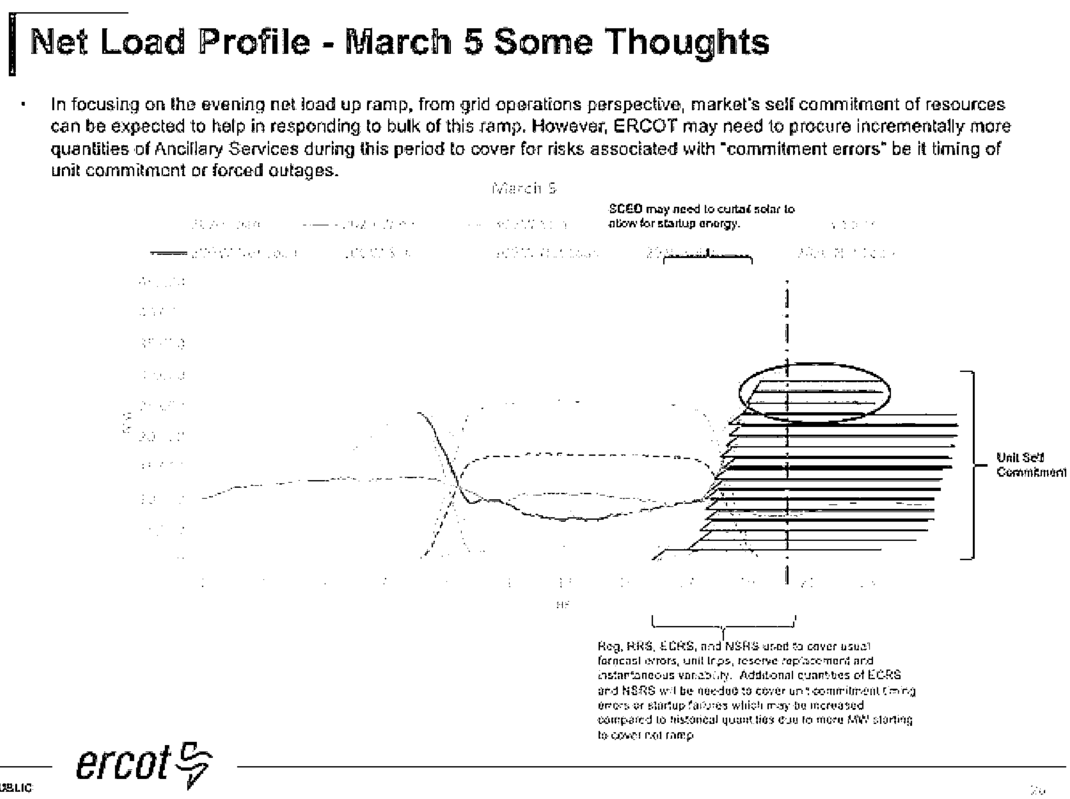
1. **Explicitly allow energy storage resources (ESRs) to participate in Non-Spinning Reserve Service (NSRS) to allow ESRs to respond to market conditions that need additional reliability support like other resources that provide NSRS. ERCOT Contingency Reserve Service (ECRS) is designed to take advantage of these fast-ramping capabilities, but ERCOT can and should incorporate these capabilities into its reliability operations as soon as possible.**
2. **Any ESR duration requirements ERCOT proposes for ECRS and NSRS should be based on detailed analyses of system operations and needs. A two-hour nameplate system duration for ESR participation in NSRS prior to the implementation of ECRS would provide a clear market signal around the product needed by the market, as would a two-hour nameplate ESR system duration requirement for the eventual ECRS product.**

These durations are supported by the analysis undertaken by ERCOT as well as by market participants.

3. **ECRS procurement volumes should be set to begin at a minimum of 3 GW when implemented to send a clear market signal for the products that best support reliable market operations and to allow investment and construction lead times ahead of increased system needs.**
4. **If an ESR built at a shorter duration wants to test and qualify for NSRS or ECRS at a de-rated capacity, that also will create more depth of possible participants in the NSRS and (eventually) ECRS markets. The growth of ESRs across ERCOT prior to implementation of ECRS will protect against the seasonal variability seen in the availability of the thermal generation fleet as units cycle through maintenance, notably in shoulder seasons when planned maintenance increases.**

At this time, ERCOT has delayed the requests from ESRs to complete the necessary market tests to provide NSRS due to questions about whether a minimum duration requirement should be imposed on ESRs providing NSRS even though such a requirement is not currently in ERCOT Protocols. Eolian strongly encourages that this issue be resolved as soon as possible. The continued delay in allowing ESRs to provide reliability services in the ERCOT market, especially now that NSRS represents 65% of the entire ancillary services market by dollar value following the increased procurement methodology introduced in July 2021, is a missed opportunity to send a clear signal to capital markets and energy investors that the services provided by ESRs are in fact highly valued by the ERCOT market. A clear signal is important given how quickly an ESR can be constructed and deployed and the Commission's stated immediate need for more sources of dispatchable generation into the ERCOT market. An open market for services will increase market participation. At a time when ERCOT requires immediate additional capacity resources, it is important to note that Tesla's 100 MW Gambit Energy Storage Project in Brazoria County was built in ~9 months. Eolian's subsidiary, Astral Electricity, constructed the Chisholm Grid 100 MW Energy Storage project in ~12 months. A clear market signal that ESRs are valued across the entire ancillary market would spur investment and deployment and bring on valuable resources faster.

A recent ERCOT analysis regarding ramping needs on the ERCOT grid[1] (shown below) confirms the expectation that unit self-commitments (i.e., generators bidding into the day-ahead and real-time markets) should respond to the bulk of even the largest ramps and, in normal operations, will meet demand. However, as noted in the graphic, the suite of ancillary services is designed to react to forecast errors, unit outages, reserve replacement and system variability. The graphic also shows the magnitude and duration of the reserve products that may be needed that require the longest response time to get through the most critical hours. As seen in the chart, the top of the generation stack is what needs to be filled most immediately if units farther below are unavailable, do not meet their commitment, or if there is unforeseen volatility in demand at the top of the demand curve. In this example of a future spring day, the top of the generator stack requires >5 GW of ancillary products that could respond nearly instantaneously but would only be generating for a maximum of two hours or less. This actual day in 2020 needed between 1-2 GW for the same peak hours of highest system risk.



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1 ERCOT Staff, Impact of Growth in Wind and Solar on Net Load, Presentation to Wholesale Market Working Group on October 25, 2021 (available at http://www.ercot.com/content/wcm/key_documents_lists/221315/NetLoad_Ramping_Analysis_v2_WMWG.pptx).

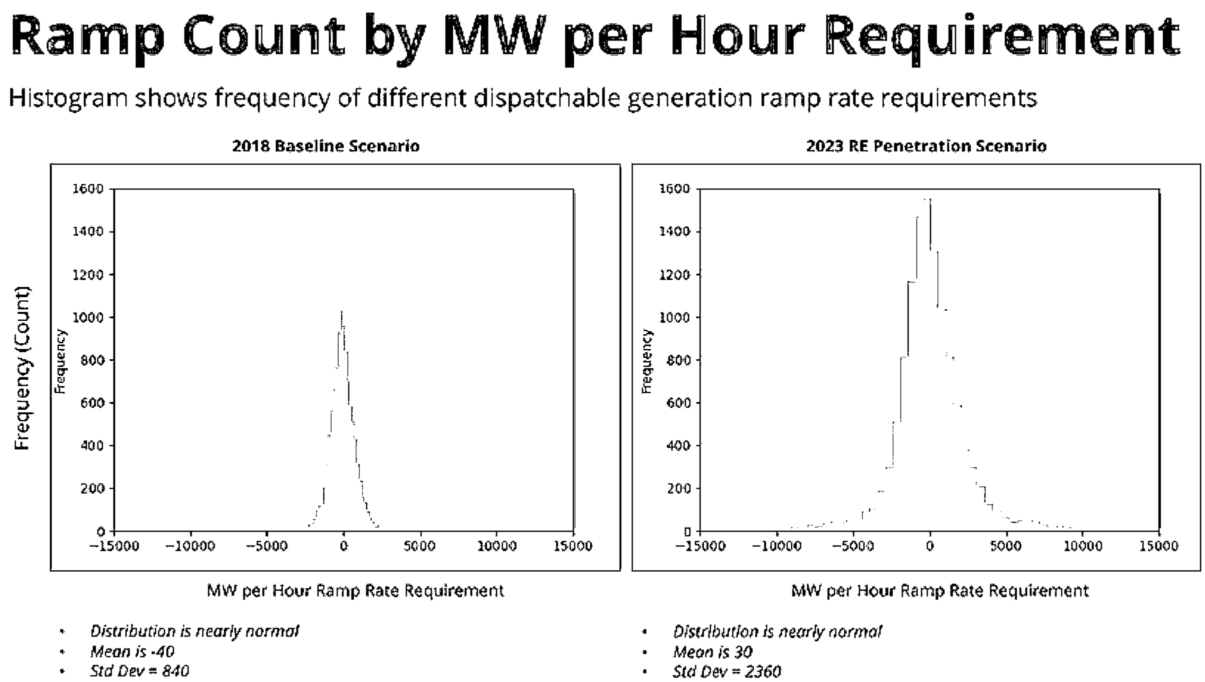
This is a very constructive graphic as it explicitly shows the expectation of how the market will be able to support larger-magnitude ramping events. This example shows that, in this future year, the procurement of the fastest-ramping products, such as RRS and ECRS (or Online Non-Spin until ECRS is available) should be at least 5-6 GW and perhaps even higher during the most critical system conditions. Currently, RRS procurement volume is ~2.8 GW depending on the season and conditions. Thus, the future ECRS procurement should be at least 3 GW once the product is available, and NSRS should see a reduction in overall procurement volumes, although the reduction may not be on a 1:1 ratio as NSRS may still be required for reserve replacement from time to time.

An independent analysis undertaken by Eolian confirms the general conclusion that the most valuable addition to meet ERCOT's immediate needs will be fast-responding capacity that is highly flexible but that is not needed to be deployed for longer than 2 hours. Eolian built a weather-driven dispatch model of ERCOT, using 5-minute granularity on historical weather with very fine spatial resolution. Then, using real weather data from previous years, we overlaid the added renewable energy generation resources that will be built across ERCOT and operational by 2023. A key reason to take this approach was to try to quantify the benefits of spatial variability across the system as a function of more resource additions.[2]

The chart below shows one result of highly-granular weather dispatch on a 5-minute interval. As more renewables are added to the system, one would expect there to be more events of larger ramps (+/- 10,000 MW/hour) that have never been seen by the system previously.

[2] ERCOT very explicitly noted in their Net Load Ramping Analysis that future build was only an extrapolation of 2020 conditions and did not consider the geographic impacts of future build locations based on actual disparate weather conditions. Thus, ERCOT's analysis tends to overstate the magnitude and duration of some ramps because it assumes that all future wind and solar generation are basically correlated to the wind/solar on the system in 2020, and that is very much not the case.

However, there also are an increase in the number of shorter duration ramps below 30 minutes. This is a key benefit of having substantial geographic diversity in the system by 2023. Thus, the future ERCOT system will see a higher number of ramps that are of shorter duration, and then also a new class of ramps that are larger in ramp rate than has been previously experienced or managed by ERCOT. These larger-duration events primarily are driven by solar ramping down near the evening peak demand, and thus are highly predictable.

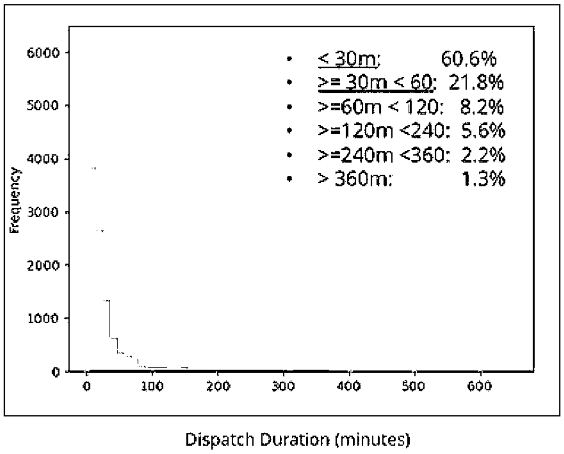


The natural next question is whether it is possible to quantify not only the frequency of ramp rates as shown above, but also the duration of the ramping events. The charts below show the results of analyzing the frequency of the duration of ramping events. The data shows that while there is a modest increase in the number of ramping events (~10% more than in the baseline), the ramps are increasingly 30 minutes or less, and are in fact heavily skewed to being less than 15 minutes. The overall percentage of ramps that are required more than 2 hours is basically unchanged compared to current system conditions. And as mentioned above, long-duration ramping events are typically diurnally- or weather-driven and can be foreseen and anticipated.

Dispatchable Generation Ramping Frequency & Duration

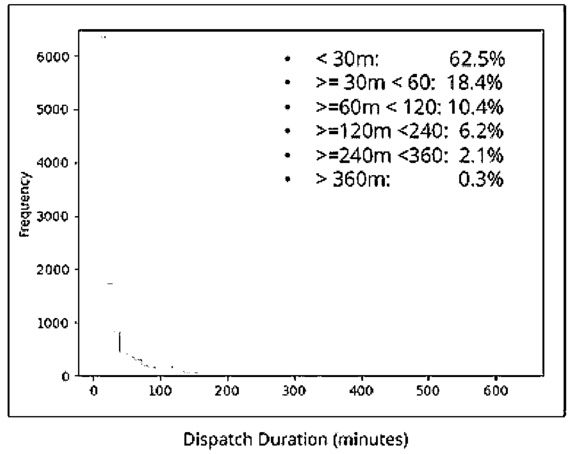
Histograms show the count and duration dispatch of generation ramping events

2018 Baseline Scenario



- *Mean Ramp Duration: 48 minutes*
- *Discrete Ramp Counts Total: 10,710*

2023 RE Penetration Scenario



- *Mean Ramp Duration: 43 minutes*
- *Discrete Ramp Counts Total: 11,837*

What conclusions can be drawn from the ERCOT Net Load Ramping Analysis and Eolian's independent analysis relevant to the Commission's question? First, as additional renewable generation is added to the grid, ERCOT can expect to see an increased frequency of short events with small MW increases and decreases. Second, ERCOT also can expect to see some larger ramps (5,000-10,000 MW per hour) that occur over durations of less than 2 hours. Third, ERCOT will require substantial capacity additions that are highly flexible both as generation and load to address the increased volume of short-duration ramps, with the vast majority of those resources needing to be available for 2 hours or less. Finally, unit self-commitments will respond to the bulk of even the largest ramps and, in normal demand, will meet demand.

These conclusions mean that, as a key component to its strategy to ensure reliable grid operations, ERCOT should allow ESRs to participate in online NSRS to support reliable operations of the grid. When ERCOT implements ECRS, a 2-hour nameplate capacity can be an appropriate duration, but until ERCOT implements ECRS, ESRs should be allowed to participate in NSRS, and, if ERCOT proposes a duration requirement for NSRS, it should be no more than 2 hours until ECRS is implemented. In order to provide clear market signals and recognizing that ECRS will reduce the need for NSRS procurement, ECRS procurement volumes should begin at a minimum of 3GW when implemented. By setting initial procurement volumes today alongside the nameplate duration requirements, ERCOT will send a clear market signal that there is a recognized need for products of this nature in the market, thereby spurring the investment needed today to be ready for the system that we expect will be seen in 2023 and 2024.

4. Are there alternatives to a load serving entity (LSE) Obligation that could be used to impose a firming requirement on all generation resources in ERCOT?

To evaluate any alternatives, the Commission first must address the nature and intent of a firming requirement, since any alternative should be addressing the key concern that a firming requirement is focused on solving. The market currently pools the operational characteristics of all resources to serve customers. To ensure second-to-second and minute-to-minute reliability, ERCOT also procures reliability products from a pool of resources and spreads the costs evenly across all consumers. Customers benefit from the reliability of the service provided, and this is the most cost-effective way to ensure reliability because it similar to a giant insurance policy that has the maximum number of subscribers. If each generation resource must procure a highly-reliable amount of firming or reliability services as its own "insurance policy," at substantial risk of penalty when that product is not available, then each generation resource will have to substantially over-procure to ensure that it is not caught short – because even a dispatchable thermal unit has scheduled and unplanned outages. The result of each generation resource self-insuring will be to create an excess of cost and insurance in the system. (This is similar to the results that would occur if all employees of a company were required to individually procure their health insurance rather than being allowed to participate in their common employer's group health plan.)

ERCOT's structure makes two basic assumptions: 1) That a free and open market where the rules and incentives are clearly delineated will provide the lowest cost and highest value outcome for consumers; and 2) That ERCOT itself provides oversight as to the key services that are critical for a fully-functional market and can socialize a select group of services and costs that otherwise would be procured on ad-hoc or uneconomic terms in an inefficient market. If both of these assumptions remain valid, then any imputed firming requirement that is designed to manifest itself as a market signal for increased assurance of highly-reliable and available capacity in specific situations would naturally flow through the ancillary markets already governed and managed by ERCOT. ERCOT has the power to create market signals for participants and investors and has already done so by creating an increasingly dynamic set of criteria and calculations for the procurement of ancillary services.

Rather than imposing a new, individual "insurance" obligation on each generation or LSE resource in the ERCOT Region, there are four steps that the Commission and ERCOT could take to assure a clear market signal around added reliability during critical market periods:

1) Define the exact criteria for an insurance product that can fill the gap after multiple market failures and generator failures have not met system needs. The ERCOT market functions quite well nearly every day. What are the true "insurance policies" needed – for daily mishaps/outages/forecasting failures or for catastrophic events that were not foreseen?

2) One potential solution for what could be catastrophic events would be for ERCOT to initiate a 3-day ahead procurement of smaller volumes of one or more ancillary products that is triggered when market conditions three days out are indicating tighter reserves. This

would be a market signal that incentivizes dispatchable generation to avoid planned outages within the window of the next 3 to 4 days and take actions to ensure availability and would compensate the resources for bidding into and clearing a volume of capacity that ensures a baseline of known dispatchable availability at key hours up to three days in advance of when system conditions may create reliability concerns. The need for this additional forward procurement could be set by an objective set of criteria that are effectively tripwires to put ERCOT and the market participants on notice that the system will pay for enhanced risk reduction due to an impending event or perception of higher risk factors. For example, any time the low temperature in Houston is forecast to be below 30 degrees, that could indicate that the system will see increased demand but also that the uncertainty band around the factors that lead to this type of event is higher, which is why there is a risk premium that needs to be addressed. A simple set of criteria, similar to what ERCOT has proposed around higher risk days for ancillary procurement, would be an objective way to put the market on notice multiple days in advance and compensate for actions taken in anticipation of those conditions, thereby helping to avoid mishaps that could have been foreseen.

3) ERCOT could further refine its ancillary procurement strategy to increase the overall procurement of specific ancillary resources above current baseline levels during known critical *hours* on daily/monthly/seasonal basis, rather than procurement of the same volume during all hours of any given day. In the same manner that ERCOT procures ancillary services today, this could have seasonal adjustments depending on when peak load or generation transitions typically occur. For example, added ancillary procurement during morning hours 6-9 am of winter months would send a market signal, as would added

ancillary procurement of flexible resources (ECRS, RRS or Online Non-Spin) for hours 16-20 on a daily basis to help ensure that operators plan their schedules and bidding behaviors around those hours. Previously, when ancillary services like RRS were provided entirely by generators that often were already running, there was a natural reason to keep the procurement volumes constant across all hours of a day. Now, with the added flexibility of resources like energy storage, ERCOT increasingly is able to adjust to hourly and sub-hourly system needs and can send very specific market signals about key hours where the value of availability and reliability are truly at a premium, since even 'high risk' days actually are mostly about a small handful of 'high risk' hours.

4. From a market perspective, the highest-risk generators are those natural gas boiler units that take hours or days to heat up/turn on, and that once running are highly inflexible. In addition, with natural gas prices now sitting at higher baseline levels, thermal boilers are hitting very high marginal costs. However, these resources are built, operational, and on the system. A key policy to ensure 'break the glass reliability' could be defined around how to keep older-vintaged gas-fired thermal boilers on the system for emergency events that might persist for days at a time, since otherwise their operating characteristics will lead to them being retired. There are many GW of these units still on the ERCOT system, and the goal would be to keep them from shutting down even though they are not currently economic in most situations. A simple solution would be to define a group of these at-risk assets, and then for a set period (e.g., 5 years), provide a generation 'value-adder' to help improve their economics, up to a maximum annual amount per MW of capacity that hits clear and proven availability requirements. Thus, if an old-vintaged gas-fired boiler unit stays available but does not run because it is not economic, it still can be guaranteed a

minimum amount of annual revenue to cover its costs. These added reliability costs would need to be borne by all customers as part of the ultimate insurance policy to ensure that truly unforeseen events can be managed by the system even after passing through all previous safeguards, but such a solution would be far cheaper than building new fleets of generation to sit in standby and likely rarely, if ever, be used.

16. Are there relevant "lessons learned" from the implementation of an LSE Obligation in the SPP, CAL-ISO, MISO and Australian markets that could be applied in ERCOT?

In the Southwest Power Pool (SPP), the requirement to provide capacity by each LSE for its zone (retail sales are not deregulated as in ERCOT, but there is the possibility of wholesale competition) has at times created unintended consequences in terms of system congestion and sustained low market prices. Since many of the LSEs in SPP also are regulated utilities and have generation in their ratebase that allows for a full passthrough of all costs, the LSEs are able to run their generators with self-dispatch that often is extremely uneconomic compared to a full wholesale market construct. In these market conditions with uneconomic choices borne by the consumers, merchant generators have been forced to sell their plants to utilities and have exited the market. See the example of AES Corporation – after the end of the 20-year purchase power agreement with Oklahoma Gas & Electric Company (OG+E), AES effectively was forced to sell the Shady Point plant to OG+E for almost no value because, without a contract, the round-the-clock economics are unfeasible. A fully-operational dispatchable plant of 360 MW was sold for $27 million, or at a cost of ~$75/kW. By comparison, a new CCGT generation costs approximately $1000/kW to construct. Thus, the result of the SPP market construct is that merchant thermal generators are largely unable to economically participate in the market unless they are tied to an

LSE, which then puts substantial market power into the hands of the LSEs rather than providing a market for full and free competition of generators.

The lesson learned from this example is that if an LSE Obligation construct provides enough added or excess revenue for many plants to run uneconomically for long periods of time in order to meet a capacity requirement at a specific hour of the day, the result could be that the real time energy markets will be flooded over long periods (depressing prices and creating unnecessary congestion) and any generators that are not part of an LSE obligation will be unable to earn enough revenue to stay solvent. Very quickly, the result could be that the majority of the revenue in the ERCOT market passes through the LSE obligations rather than through the real time energy markets, and thus the majority of activity and transactions moves out of the direct and visible clearinghouse of the ERCOT market itself.

CONCLUSION

Eolian appreciates the opportunity to provide these responses to the Commission's questions and looks forward to working with the Commission and other interested parties on these issues.

Respectfully submitted,

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PROJECT NO. 52373

REVIEW OF WHOLESALE	**§**	**PUBLIC UTILITY COMMISSION**
ELECTRIC MARKET DESIGN	**§**	**OF TEXAS**

COMMENTS OF EOLIAN

EXECUTIVE SUMMARY

Question 2: What modifications could be made to existing ancillary services to better reflect seasonal variability?

Ancillary services are equally important throughout all seasons for the reliable operation of the market and are required on a daily basis to manage missed forecasts and unforeseen events as well as significant generator outages. Weather-driven variability around intermittent resources such as wind and solar as well as thermal generator outages (either unplanned or for planned maintenance) is now effectively equally probable in all seasons due to a combination of human behaviors, market signals, and weather volatility. For example, June of 2021 saw the unplanned outage of Comanche Peak for multiple weeks during an early summer heatwave that resulted in concerns around reserve margins and increased market prices. In order to ensure reliability throughout the year and to avoid inadvertent correlation of entire ancillary markets to seasonal fluctuations impacted by operator behavior (such as the 20+ GW of thermal outages this October), Eolian recommends the following modifications to ERCOT's existing ancillary services:

1. Explicitly allow energy storage resources (ESRs) to participate in Non-Spinning Reserve Service (NSRS) to allow ESRs to respond to market conditions that need additional reliability support like other resources that provide NSRS. ERCOT Contingency Reserve Service (ECRS) is designed to take advantage of these fast-ramping capabilities, but ERCOT can and should incorporate these capabilities into its reliability operations as soon as possible.
2. Any ESR duration requirements ERCOT proposes for ECRS and NSRS should be based on detailed analyses of system operations and needs. A two-hour nameplate system duration for ESR participation in NSRS prior to the implementation of ECRS would provide a clear market signal around the product needed by the market, as would a two-hour nameplate ESR system duration requirement for the eventual ECRS product. These durations are supported by the analysis undertaken by ERCOT as well as by market participants.
3. ECRS procurement volumes should be set to begin at a minimum of 3 GW when implemented to send a clear market signal for the products that best support reliable market operations and to allow investment and construction lead times ahead of increased system needs.
4. If an ESR built at a shorter duration wants to test and qualify for NSRS or ECRS at a de-rated capacity, that also will create more depth of possible participants in the NSRS and (eventually) ECRS markets. The growth of ESRs across ERCOT prior to implementation of ECRS will protect against the seasonal variability seen in the availability of the thermal generation fleet as units cycle through maintenance, notably in shoulder seasons when planned maintenance increases.

Question 4: Are there alternatives to a load serving entity (LSE) Obligation that could be used to impose a firming requirement on all generation sources in ERCOT?

ERCOT currently procures reliability products from a pool of resources and spreads the costs evenly across all consumers, with each customer paying a portion of the 'insurance premium.' If each generation resource or LSE must procure a highly-reliable amount of firming or reliability services as its own "insurance policy," at substantial risk of penalty when that product is not available, then each generation resource will have to substantially over-procure to ensure that it is not caught short – because even a dispatchable thermal unit has scheduled and unplanned outages. The result of each generation resource self-insuring will be to create an excess of cost and insurance in the system. Rather than impose a new, individual "insurance" obligation on each individual generation or LSE resource in the ERCOT Region, there are four steps that the Commission and ERCOT could take to assure a clear market signal around added reliability during critical market periods:

1) Define exact criteria for an insurance product that can fill the gap after multiple market failures and generator failures have not met system needs
2) Initiate a 3-day ahead procurement of smaller volumes of one or more ancillary products that is triggered when objectively-set 'tripwire' market conditions are indicating tighter reserves in a window looking forward three days. This would be a market signal that incentivizes dispatchable generation to avoid planned outages within the window of the next 3 to 4 days and take actions to ensure availability, and would indicate to ERCOT and market participants possible shortages days in advance of when system conditions may actually create reliability concerns.
3) Increase the overall procurement of specific ancillary resources above the current baseline volumes during known critical *hours* on a daily/monthly/seasonal basis, rather than procurement of the same volume during all hours of any given day. For example, added ancillary procurement during morning hours 6-9 am of winter months would send a market signal, as would added ancillary procurement of flexible resources (ECRS, RRS or Online Non-Spin) for hours 16-20 on a daily basis to help ensure that operators plan their schedules and bidding behaviors around those hours.

Question 16: Are there relevant "lessons learned" from the implementation of an LSE Obligation in the SPP, CAL-ISO, MISO and Australian markets that could be applied in ERCOT?

In SPP, we have seen evidence that if an LSE Obligation construct provides enough added or excess revenue incentive for many plants to run uneconomically for long periods of time in order to meet a capacity requirement at a specific hour of the day, the result can be that the real time energy markets are flooded over long periods (depressing prices and creating unnecessary congestion) and any generators that are not part of an LSE obligation will be unable to earn enough revenue to stay solvent. Very quickly, the result could be that the majority of the revenue in the ERCOT market passes through the LSE obligations rather than through the real time energy markets, and thus the majority of activity and transactions moves out of the direct and visible clearinghouse of the ERCOT market itself.